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(54) Title: FLOW METER FOR MULTI-PHASE MIXTURES

(57) Abstract

A method and apparatus is disclosed for determining the flow rates of fluid phases in a pipe containing multiple fluid phases. A Venturi is provided to measure total volumetric flow rate measurement and a holdup measurement is taken approximately 3 – 10 pipe diameters downstream of the Venturi. The holdup measurement is made at a downstream location where a substantial amount of mixing occurs and the difference between the velocities of the fluid phases can effectively be ignored. The flow rates of the phases can thus be determined directly from the holdup measurements.

FLOW METER FOR MULTI-PHASE MIXTURES

FIELD OF THE INVENTION:

The present invention relates to the field of
5   flow meters for multiphase mixtures. In particular,
the invention relates to flow meters for oil and water
mixtures in hydrocarbon boreholes.

BACKGROUND OF THE INVENTION:

10   The measurement of oil and water flow rate in
each producing zone of an oil well is important to the
monitoring and control of fluid movement in the well
and reservoir. In addition to a flow meter, each zone
may have a valve to control the fluid inlet from that
15   zone. By monitoring flow rates of oil and water from
each zone and reducing flow from those zones producing
the highest water cut (i.e., ratio of water flow rate
to total flow rate), the water production of the entire
well can be controlled. This, in addition, allows the
20   reservoir oil to be swept more completely during the
life of the well.

Ideally, a flow meter in such an installation
should satisfy several criteria: 1) it should be
25   extremely reliable and operate for years at downhole
temperature and pressure; 2) it should operate in both
stratified (near-horizontal) and dispersed flow regimes
over a wide range of total flow rate and cut; 3) it
should not require that the completion be oriented
30   azimuthally in any particular way during installation;
4) it should not require licensing of radioactive

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sources and, finally; 5) the flow meter should allow
small changes in water cut and flow rate to be
detected.

5   Typically, downhole flow meters determine the
holdup (volume fraction of oil or water) and the
velocity of the oil phase, the water phase, or both.
The flow rate of water is then determined from the
product of water holdup α_w, the pipe area A, and the
10   velocity of water U_w. An analogous relation holds for
oil flow rate. In general, the velocities of water and
oil are different. The slip velocity (difference in oil
and water velocities) depends on many parameters, such
as the inclination angle of the flow pipe (i.e.
15   deviation), roughness of the pipe wall, and flow rates
of the two phases. In general, one must measure the
holdup and velocities of both oil and water to
determine oil and water flow rate uniquely. In
practice, sometimes one measures the velocity of only
20   one phase and uses a theoretical or empirically
determined slip law to obtain the other. This has a
number drawbacks including inaccuracies due to
differences conditions used as inputs to the model and
the actual conditions downhole.
25

          A common method to determine the velocity of
a fluid is to measure the rotation rate of a turbine
blade in the flow stream. In single phase flow, the
rotational velocity of the turbine is simply related to
30   the velocity of the flow. However, in mixed oil and

water flow the response of the turbine can be so
complicated as to be uninterpretable.

5   Another method of velocity measurement uses
tracers. A tracer is injected into the phase of choice
(oil or water) and, at a known distance downstream, a
sensor detects the time of passage of the tracer. The
velocity is computed from the known distance and time
of travel. One disadvantage of the tracer method for
10   permanent downhole use is the need for a reservoir of
tracer material and a mechanical tracer injector. The
reservoir limits the number of measurements and the
injector, being a mechanical device, is prone to
sticking and failure.

15
Another method of velocity measurement uses
local capacitance or resistance sensors. This method is
appropriate for flow regimes in which one phase is
dispersed as droplets in another continuous phase. As a
20   droplet passes one of the sensors, a signal is produced
for a time duration related to the speed of the
droplet. Given knowledge of the droplet size by other
means, the velocity of the droplet can be deduced. One
disadvantage of this method is that it does not work at
25   all in a stratified flow regime, since it relies on the
existence of bubbles.

There are other methods of flow measurement
that can be used, which are not described herein, but
30   are familiar to those skilled in the art.

Another method of velocity measurement uses a

Venturi.   In single phase flow, a Venturi generally

obeys the Bernoulli equation which relates volumetric

flow rate Q to fluid density ρ and pressure drop from

5   the inlet to the throat of the Venturi:

$$Q = C \sqrt{\frac{2\Delta p / \rho}{\left(\frac{1}{A_{throat}^2} - \frac{1}{A_{inlet}^2}\right)}} \qquad \text{Equation 1}$$

where C is the discharge coefficient which is

10   approximately unity but depends on the geometry of the

Venturi, Δp is the pressure drop from Venturi inlet to

throat, and A_{throat} and A_{inlet} are the throat and inlet

cross sectional areas, respectively. The same equation

can be used to determine the combined oil and water

15   flow rate where the density in this case is the average

mixture density in the throat of the Venturi. In

practice, the square root in the equation makes it

relatively insensitive to errors in both the density

and pressure determinations.

20

A common method to determine the holdup in a

flow of oil and water is to measure the average density

of the fluid. Since oil at downhole pressure and

temperature typically has a density which is smaller

25   than that of water (around 0.7 g/cm^3 compared to

1.0 g/cm^3), the oil and water holdups α_o and α_w can be

determined proportionately from the mixture density by

the relations

$$\alpha_o = \frac{\rho_w - \rho_{mix}}{\rho_w - \rho_o} \qquad \text{Equation 2}$$

$$\alpha_w = \frac{\rho_{mix} - \rho_o}{\rho_w - \rho_o} \qquad \text{Equation 3}$$

5   A common method to determine the mixture
density is to measure the hydrostatic pressure of a
column of fluid with a gradiomanometer. This device
relies on having a component of the gravitational force
10   vector along the axis of the flow pipe. This type of
device, however, fails when the flow pipe is horizontal
because the gravitational force vector is perpendicular
to the pipe axis.

15   Another method to determine holdup uses
capacitor plates to measure the bulk dielectric
constant of the fluid. This method is used for flow
regimes in which the water is dispersed in bubbles
within an oil-continuous medium. It fails in stratified
20   flow or in flow regimes in which the oil is dispersed
in bubbles within a water-continuous medium.

        Another method to determine holdup uses
electrodes or an inductive coupling to measure the bulk
25   resistance of the fluid. This method is used for flow
regimes in which the oil is dispersed in bubbles within
a water-continuous medium. It fails to work properly in
stratified flow or in flow regimes in which the water
is dispersed in bubbles within an oil-continuous
30   medium.

Another method to determine holdup uses
arrays of capacitor plates or resistance electrodes to
measure dielectric constant or resistance in the fluid
immediately surrounding the sensor. The accuracy of
5   this method depends on the number of sensors in the
array. The disadvantages with this method are that
small probes are prone to damage and fouling and the
probes are invasive to the pipe, preventing other tools
or devices from passing by them freely.
10

Mixers of various types have been used to mix
the oil and water, so as to effectively reduce the slip
and allow for more accurate determination of the flow
rates. Some mixers are simply small orifices in plates
15   of suitable material. Others comprise more elaborate
fins having certain twists or curled shapes. There are
a number of disadvantages, however, in using
conventional mixers when trying to measure the flow
rates of oil and water downhole. For example, the
20   mixer often obstructs the borehole, such that it may be
difficult to pass certain equipment such as production
logging tools, etc. Mixers also can produce
unacceptable amounts of pressure loss. Additionally,
mixers are prone to excessive wear with age.
25

It is possible to measure the pressure
differential upstream and downstream of a conventional
mixer in an attempt to determine the total flow rate of
oil and water. This technique, however, has a number
30   of drawbacks. For example, the accuracy of the flow
rate determined by this method is likely to be much

lower than using a Venturi, and, in general, greatly
dependent upon the flow rates. Using a mixer to
measure pressure differential can also lead to
inaccuracy due to sensitivity to the exact location of

5   pressure measurement. Using a conventional mixer in
this fashion would also be prone to problems associated
with wear. For example, in an orifice mixer, the
relationship between the pressure differential and the
velocity could change significantly over time due to

10   slight changes in shape and size of the orifice caused
by wear.

U.S. Pat. No. 4,856,344, issued to Hunt,
discloses using a Venturi for obtaining a pressure

15   differential and using a gradiomanometer upstream and
through the Venturi to measure density. Hunt discloses
using an iterative process to estimate the relative
flow velocities. Hunt also discloses using a separate
upstream step discontinuity to mix the fluids upstream

20   of the gradiomanometer. However, the method disclosed
in Hunt is prone to problems associated with relying on
estimates of the flow velocities (i.e. a slip model),
using separate additional mixers upstream, and using a
gradiomanometer (e.g. nonfunctional when pipe is

25   horizontal, and low accuracy when near-horizontal).

U.S. Pat. No. 5,361,632, issued to Magnani,
discusses a holdup measurement using a combination of
gradiomanometer and gamma-ray densitometer. Thus, the

30   method of Magnani is prone to problems associated with
using a gradiomanometer which is not suitable for

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measurements in near-horizontal pipes. Furthermore,
the method obstructs the borehole and would not be
suitable for permanent installation.

5   U.S. Pat. No. 5,661,237, issued to Dussan et
al. discusses a holdup measurement using local probes.
There is no mention of a Venturi, however. The method
obstructs the borehole and would not be suitable for
permanent installation.
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          U.S. Pat. Nos 5,893,642 and 5,822,390, issued
to Hewitt et al. disclose a method of using a mixer to
measure flow rates. However, this method suffers from
the disadvantages of using a mixer as described above.
15 For example, the mixer obstructs borehole and is not
suitable for permanent installation due to problems of
wear.

20 SUMMARY OF THE INVENTION:
          Thus, it is an object of the present
invention to provide a flow meter suitable for downhole
placement that is extremely reliable and capable of
operating for years at downhole temperatures and
25 pressures. It is another object of the invention to
provide a flow meter that is capable of operating in
both stratified (near-horizontal) and dispersed flow
regimes over a wide range of total flow rate and cut.
It is another object of the invention to provide a flow
30 meter that does not require that the wellbore be
oriented azimuthally in any particular way during

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installation. It is another object of the invention to
provide a flow meter that does not require the use of
relatively strong radioactive sources. It is another
object of the present invention to provide a flow meter
5   that is capable of detecting small changes in water cut
and flow rate. It is another object of the invention
to alleviate the problems associated with the use of
conventional mixers, including the possible problems
associated with measuring the pressure differential
10   upstream and downstream of a conventional mixer. It is
another objective of this invention to provide a
measurement of a phase transition pressure.

In this invention, we combine a Venturi total
15   volumetric flow rate measurement with a holdup
measurement approximately 3 - 10 pipe diameters
downstream of the Venturi. The invention makes use of
a flow instability downstream of the Venturi throat.
When the oil and water flow accelerates into the throat
20   of the Venturi, the streamlines converge from their
upstream value and the pressure drops as the
hydrostatic head is converted into kinetic energy.
Conversely, as the flow enters the diffuser section the
pressure recovers as the flow decelerates. This adverse
25   pressure gradient can lead to separation of the flow
within the boundary layer at some position downstream
of the throat of the Venturi. That position depends on
the geometry of the Venturi, the individual oil and
water flow rates, the deviation angle of the pipe to
30   the horizontal, and the densities of the two fluids.
The main flow expands beyond the Venturi as a jet of

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approximately uniform velocity bounded by a free shear
layer, and such shear layers are prone to Kelvin-
Helmholtz type instabilities that grow and are
convected downstream. In the diffuser of the Venturi,

5   an instability such as this grows and perturbs the
interface between the two fluids. The amplitude of the
instability depends on the geometry of the Venturi, the
deviation of the pipe, the densities of the fluids, and
the flow rates. An instability of sufficient strength

10   causes the interface to roll up and break with a
resulting mixing of the two layers completely across
the pipe.

       According to the invention, a method of
15   determining the flow rate of a first fluid phase in a
pipe containing at least two fluid phases is provided.
The fluid phases flow through an upstream pipe, a
constriction, which is preferably a Venturi, and a
downstream pipe. The differential pressure of the -

20   fluid phases is measured such that it can be related to
the total flow rate of the fluid phases through the
section of pipe. The differential pressure is
preferably measured between the upstream pipe and the
throat of the Venturi. The volume fraction of the

25   first fluid phase (preferably water) is determined by
making a measurement at a location downstream of the
constriction where a substantial amount of mixing of
the at least two fluid phases is present, which results
from the fluid passing through the Venturi. The flow

30   rate of the first fluid (preferably water) is

determined by assuming its velocity is substantially
the same as that of the other fluid phases.

BRIEF DESCRIPTION OF THE DRAWINGS:

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Figure 1 is a perspective view of a section
of pipe including a Venturi used to measure velocity
and to mix oil and water according to a preferred
embodiment of the invention;

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Figure 2 is a detailed cross sectional view
of a Venturi used to measure velocity and to mix oil
and water according to a preferred embodiment of the
invention;

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Figure 3 is a perspective view of a section
of pipe including a Venturi and other equipment used to
measure velocity and to mix oil and water according to
a preferred embodiment of the invention;

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Figure 4 is a graph illustrating the
relationship between water holdup compared to the water
cut as experimentally measured at a Venturi throat
section;

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Figure 5 is a graph illustrating the
relationship between water holdup compared to the water
cut as experimentally measured at a location upstream
from a Venturi;

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Figure 6 is a graph illustrating the
relationship between water holdup compared to the water
cut as experimentally measured at a location downstream
from a Venturi, according to a preferred embodiment of
5   the invention;

Figs. 7a-c illustrate the effects of
different orientations of the attenuation path where
the flows of oil and water are not sufficiently mixed;
10 and
Figure 8 is a graph comparing water holdup
measured downstream and water cut, for various flow
rates, cuts, inclinations and attenuation path
orientations.

15

Figure 9 is a graph showing the density
determined with the preferred embodiment as a function
of pressure.

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DETAILED DESCRIPTION OF THE INVENTION:

Figure 1 is a perspective view of a section
of pipe 100 including a Venturi 110 used to measure
25 velocity and to mix oil and water according to a
preferred embodiment of the invention. The direction
of flow is shown by arrow 102. Pipe section 112 is
upstream of the Venturi 110. Venturi 110 comprises a
tapered inlet section 114, a Venturi throat 116, and a
30 Venturi diffuser 118. Pipe section 120 is downstream
of the Venturi 110, and has diameter 124. According to

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the invention, it has been found that significant
mixing of oil and water takes place downstream of
Venturi 110 and therefore it is a good place to make a
holdup measurement. In Figure 1, downstream location

5   122 is shown to be a suitable location for measuring
the holdup.

         Figure 2 is a detailed cross sectional view
of a Venturi used to measure velocity and to mix oil

10   and water according to a preferred embodiment of the
invention. The direction of flow is shown by arrow
102. Inlet 114 is smoothly tapered from the diameter
of the upstream section 112 to the diameter of the
Venturi throat 116. As shown in Figure 2, the Venturi

15   throat 116 has a diameter narrower than upstream
section 112. The walls of the Venturi throat 116 are
preferably approximately parallel along the direction
of flow 102. The Venturi diffuser 118 is gradually
tapered from the diameter of the Venturi throat 116 to

20   approximately the diameter 124 of the downstream
section 120. Upstream section 112, inlet 114, throat
116, diffuser 118, and downstream section 120 all have
approximately circular cross-sections, and the diameter
of the throat 116 is preferably about half that of the

25   upstream pipe section (i.e. beta = 0.5). For, example
if the upstream pipe section diameter is 15 cm, then
the throat is preferably about 7.5 cm. Preferably,
Venturi 110 is designed to meet the ISO standard and is
designed so as to allow for relatively accurate

30   measurements of differential pressure, while impeding
the flow as little as possible. However, it is

contemplated that other Venturi dimensions and
geometries could also facilitate an accurate
differential pressure measurement and provide
sufficient mixing for an accurate holdup measurement,
5   according to the invention. The location with respect
to the Venturi where the holdup measurements were taken
is shown at downstream location 120. As will be
described in greater detail below, measuring the holdup
at locations downstream as shown advantageously allows
10   for much more accurate determinations of flow rates.
As shown in Figure 2, a port 134 is provided to measure
the pressure at a location within Venturi throat 116.
Another port, not shown in Figure 2, is provided
upstream which in combination with port 134 allows for
15   measurement of pressure differential.

Figure 3 is a perspective view of a section
of pipe including a Venturi and other equipment used to
measure velocity and to mix oil and water according to
20   a preferred embodiment of the invention.

In a preferred embodiment shown in Figure 3,
the invention combines a Venturi 110 with a simple
gamma-ray attenuation density measurement. A
25   differential pressure sensor 130 measures the pressure
drop between the inlet 112 (at port 132) and the
Venturi throat 116 (at port 134). (Note that although
the pressure sensor 130 is shown to measure the
differential pressure between the locations of ports
30   132 and 134, other locations could be chosen. For
example, although unconventional, one of the

measurements could be taken downstream of the Venturi.)
A flow instability develops as the flow exits from the
Venturi diffuser 118. A source of gamma-rays 142 is
provided which is preferably ^{133}Ba, (although ^{137}Cs or

5   other isotopes can also be used). Preferably, source
of gamma-rays 142 is sufficiently weak as to be exempt
from licensing. A gamma-ray detector 144, preferably a
NaI(Tl) scintillation detector, is placed diametrically
opposite source 142. The gamma-ray source 142 and

10   detector 144 are preferably placed at a particular
location which is a distance 3-10 times the downstream
pipe diameter 124. With no fluid in the pipe, gamma-
rays from the source travel across the pipe and are
detected in the gamma-ray detector with a certain rate

15   R_s. With fluid in the pipe, the gamma-rays are
scattered and absorbed according to the density of the
fluid, with the result that the detection rate R is
reduced according to

20                 $$R = R_s e^{-\tau \rho d}$$ Equation 6

     where d is the diameter of the pipe, ρ is the
average density of fluid along the path between source
and detector, and τ is the mass attenuation

25   coefficient, which is essentially constant for typical
borehole fluids. One may calibrate the device with a
known fluid, for instance water, giving

                 $$R_w = R_s e^{-\tau \rho_w d}$$ Equation 7

30
     Then one may determine the average oil holdup
α_o (or water holdup using the relation $\alpha_w = 1 - \alpha_o$) of a

mixture of oil and water along the attenuation path of
the gamma-rays (across the diameter of the pipe) from
the mixture density ρ_{mix} and Equations 2 and 7 according
to

5

$$\rho_{mix} = \frac{\ln(R_s) - \ln(R_{mix})}{d\tau} \qquad \text{Equation 8}$$

$$\alpha_o = \frac{\ln(R_{mix}) - \ln(R_w)}{d\tau(\rho_w - \rho_o)} \qquad \text{Equation 9}$$

10   This holdup, which is the average along the
attenuation path, is equal to the pipe area averaged
holdup because the oil and water are mixed relatively
thoroughly throughout the pipe cross-section. It has
been found on the basis of flow loop experiments that
15 this condition is satisfied approximately 3-10 pipe
diameters downstream of the downstream end of the
Venturi diffuser even if the flow entering the Venturi
is stratified.   However, a substantial improvement in
the accuracy of determining the relative flow rates of
20 water and oil can be obtained under some circumstances
by measuring the holdup at any location from just
downstream of the Venturi to about 20 pipe diameters.
For example, it may be sufficiently accurate to measure
the holdup at locations where the stratification has
25 been significantly perturbed.

        It is possible to determine density from
direct PVT measurements on the fluid, or by determining
either the decay time or resonance frequency of a
30 vibrating body, or from an equation of state with the

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appropriate input data (usually the chemical
composition and pressure-volume-temperature
measurements of the fluid). An equation of state is a
function that provides thermodynamically consistent
5   data on the configurational properties of liquids and
gases. The term equation of state is used to describe
an empirically-derived function which provides a
relation between pressure, density, temperature, and
for mixtures composition. The samples used for these
10   analyses can be obtained from separator, surface or
bottom hole sampling. The latter provides a sample at
the location of the flowmeter and as such is the
preferred method. A Wireline tool, such as either the
MDT or RFT can be used to obtain these samples. When
15   three phases are present, detailed pressure-volume-
temperature-composition measurements of the fluid are
preferably performed to provide density and phase
volumes. The presently preferred method is to obtain
the densities with an equation of state from
20   compositional data. In the case where oil, gas and
water are present, the volume or mole fraction of the
gas and oil are also preferably obtained from the
equation of state to facilitate the determination of
water holdup.

25

It is presently believed that measuring the
holdup in a region approximately 3-5 diameters from the
Venturi can provide even greater accuracy over a wider
range of flow rates. Finally, under the tested
30   conditions, it is believed that measuring the holdup at
approximately 5 diameters from end of the diffuser will

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provide the greatest accuracy in relative flow rate
measurement.

   In general, the distance from the Venturi at
5 which a suitable amount of mixing occurs will depend on
many factors. First the amount of mixing needed to
substantially improve flow rate determination depends
on the method of holdup measurement. For example, if
more than one gamma-ray beam is used, at different
10 angles, a lower amount of mixing may be acceptable to
accurately determine the holdup and water cut. Second,
the distance from the Venturi at which suitable mixing
occurs depends on the particular geometry and
anticipated flow rates of the fluids in the Venturi.
15 Furthermore, the density and viscosity of the fluids,
and the deviation can influence the amount and location
of mixing caused by the Venturi.

   In addition, continual monitoring of the
20 average density of fluid provides a means of
determining phase boundaries.   Indeed, the gamma-
radiation attenuation, which determines the density of
the objects in the radiation path is proportional to
the volume fraction of each phase multiplied by the
25 density of each phase. This is the preferred method for
phase boundary detection as shown in Figure 9 for a
bubble point. Figure 9 is a graph showing the density
determined with the preferred embodiment as a function
of pressure. Clearly, the bubble pressure is easily
30 detected as a discontinuity in $(\partial \rho / \partial p)_T$ indicates the

bubble. Other methods, such as PVT experiments,
familiar to those skilled in the art could also be
used.

5   The total flow rate is computed from Equation
1, using the mixture density computed from Equation 8.
Holdup is computed from Equation 9 and the oil and
water flow rates are computed from Equations 4 and 5.

10   Figure 4 is a graph illustrating the
relationship between water holdup compared to the water
cut as experimentally measured at a Venturi throat when
flowing various mixtures of oil and water. The vertical
axis is the water holdup, or the volume fraction of
15 water. The horizontal axis is water cut, or the ratio
of water flow rate to the total volumetric flow rate.
The measurements were taken at different total
volumetric flow rates ranging from 40 cubic meters per
hour to 100 cubic meters per hour. As can be seen in
20 Figure 4, the water holdup varies significantly from
the water cut at all measured flow rates.

          Similarly, Figure 5 is a graph illustrating
the relationship between water holdup compared to the
25 water cut, but the holdup measurements were made at a
location upstream from a Venturi. As in Figure 4, the
holdup measurements do not accurately reflect the water
cut values for most of the flow rates measured.

30   Figure 6 is a graph illustrating the
relationship between water holdup compared to the water

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cut as experimentally measured at a location downstream
from a Venturi, according to a preferred embodiment of
the invention. Specifically, in Figure 6, the water
holdup was measured at a location approximately 3 pipe

5   diameters downstream from the downstream end of the
Venturi diffuser. As can be seen in Figure 6, in stark
contrast from the data in Figures 4 and 5, the measured
holdup accurately reflects the water cut at all the
measured flow rates.

10

Thus, we have experimentally found that a
significant instability exists downstream of the
Venturi regardless of the flow regime at the inlet of
the Venturi as long as the total flow rate exceeds a

15 minimum value. For example, for a 15 cm diameter
upstream section of pipe with a Venturi throat diameter
of about 7.5 cm (i.e. beta=0.5), approximately 20 cubic
meters per hour. Because of this instability and the
mixing that it produces, oil and water are well-mixed

20 approximately 3 -10 pipe diameters downstream of the
Venturi exit, although as mentioned above, other
measuring the holdup at other locations may be suitable
in certain situations.

25   Due to the well-mixed condition, the oil and
water are nearly homogeneously distributed throughout
the pipe and the slip velocity between oil and water is
very small. In such a condition, the water holdup is
equal to the water cut X_w, or ratio of the water

30 volumetric flow rate to the total flow rate.

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Conversely, the oil holdup is equal to the oil cut, or
ratio of the oil volumetric flow rate to the total flow
rate. This is important because the oil and water flow
rates can then be obtained directly from the product of

5 the respective holdup and total flow rate from the
Venturi:

$$Q_o = X_o Q = \alpha_o Q \quad \text{Equation 4}$$

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$$Q_w = X_w Q = \alpha_w Q \quad \text{Equation 5}$$

Advantageously, no slip model is required.
Even if the water holdup is not exactly the same as the

15 water cut, differences of a few percent can be
incorporated as empirical corrections to the equations
given above. Preferably, the holdup measurement is
made at a location downstream of the Venturi where the
difference between the water holdup and the water cut

20 is be negligible for the particular measurement
requirements the application at hand.

According to the invention, many of methods
of holdup measurement, including most of those

25 mentioned above, could be used to measure holdup at a
location downstream from the Venturi, so long as the
downstream measurement is taken at a location that
experiences a suitable amount of mixing. For example,
it is possible to determine holdup by measuring the

30 sound speed of the fluid, or by determining either the
decay time or resonance frequency of a vibrating body.
(Note that using a conventional gradiomanometer may not

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be suitable, since that method ordinarily relies on
pressure differentials taken over lengths that are
substantially greater than length of mixed oil and
water provided by the Venturi.) However, the preferred

5   embodiment in this invention is to determine the fluid
density by measuring the attenuation of gamma-rays
across a diameter of the pipe. The determination of
density from gamma-ray attenuation is well known in the
art. Conventionally, because of temporal

10 inhomogeneities in the flow, large radioactive sources
are usually used to measure density in a short period
of time. However, because in the present invention the
flow is relatively homogeneous in time and space, the
density measurement may be taken over several seconds

15 or minutes, allowing the use of very weak sources that
are exempt from licensing. Additionally, this very
simple measurement can use detectors that are similar
to those already in use in conventional Wireline gamma-
ray logging tools.

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        In a well-mixed flow, the average fluid
density determined across a diameter of the pipe, such
as given by gamma-ray attenuation, is equivalent to the
average fluid density over the entire pipe. Also, there

25 is little slip and the water holdup is essentially
equal to the water cut.

        It is important to note that such conditions
do not exist at other locations in the pipe, such as

30 upstream of the Venturi or in the Venturi throat. At
each of the locations upstream, downstream and in the

22

Venturi throat, the gamma-ray attenuation has been
measured along a vertical path and the density and
holdup extracted from it for several different total
flow rates. The water holdup at the Venturi throat is

5   compared to the water cut in Fig. 4. Clearly, the
holdup is not equal to the cut, indicating that the
mixture is not homogeneous. In Fig. 5, the water holdup
upstream is compared to the water cut. Again, the
holdup is not equal to the cut. Finally, in Fig. 6, the

10   water holdup downstream at a spacing of 3 pipe
diameters from the Venturi exit is plotted against
water cut. In this case the holdup is very nearly equal
to the cut.

15   Also, it is important to note for holdup
measurements made upstream and at the Venturi throat,
the orientation of the attenuation path is important
because the flow is not homogeneous. For example,
upstream and in near-horizontal orientation of the

20   pipe, the flow will often be stratified. Figs. 7a-c
illustrate the effects of different orientations of the
attenuation path where the flows of oil and water are
not sufficiently mixed. Clearly, the average density
along the three paths is different. For example, in

25   Figure 7c the attenuation path is located entirely in
the oil. In this instance, there is no information at
all about the average density or holdup.

            However, at downstream locations where a
30   substantial mixing occurs (for example, at a spacing 3-
10 pipe diameters from the downstream end of the

                                23

Venturi diffuser) the flow is homogeneous and the
attenuation measurement provides the mixture density
and holdup.

5   Some of the further advantages of measuring
the holdup at such downstream locations are shown in
Figure 8. Figure 8 is a graph comparing water holdup
measured downstream and water cut, for various flow
rates, cuts and inclinations and attenuation path
10   orientations. The holdup measurements were taken at a
distance approximately three pipe diameters downstream
of the Venturi. The data were taken at flow rates
varying from 60 to 120 cubic meters per hour, at
inclinations (i.e. the vertical tilt of the flowpath)
15   ranging from 70 to 90 degrees, and at three attenuation
path orientations as shown in Figs. 7a-c. As can be
seen from the graph, the measured holdup very closely
approximates the water cut over a wide range of values.
Significantly, the holdup is nearly equal to the cut
20   over the different orientations and inclination angles.

While preferred embodiments of the invention
have been described, the descriptions are merely
illustrative and are not intended to limit the present
25   invention. For example, although the present invention
has thus far been principally described in connection
with measuring fluid flow rates in mixtures of oil and
water, the present invention is also applicable to
facilitate the determination of fluid flow rates in
30   other mixtures. In general, a Venturi could also be
used to determine velocity and as a mixer for mixtures

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of any fluids, including gas phases. For example, two
liquids, one liquid and one gas, or two liquids and one
gas. The geometry of the Venturi should be designed so
as to facilitate a suitable amount of mixing at the

5   flow rates of interest, and the measurement of the
holdup should be taken at a downstream location where a
sufficient amount of mixing takes place to enable an
accurate determination of flow rate from the measured
volume fraction.

10

        In the case where a gas phase is present, the
holdup can be determined from measurements of density
with either equations (2) or (3), and an equation of
state, or direct measurements, can be used to determine

15   the oil and water densities. In the presence of three
phases, oil, water and gas below the bubble pressure,
the average hydrocarbon density can be determined with
an equation of state based on a compositional analysis.
For three phase fluid, oil, water, and gas, the volume

20   (mole fraction) average density of the oil and gas are
used in the analysis which is consistent in this domain
with the density determined with the gamma-ray for the
water, oil and gas. The preferred method makes use of
an equation of state.

25

        As mentioned, the present invention is
applicable to mixtures of three or more phases, where a
suitable Venturi can be used to both measure velocity
and mix the various phases. So long as the velocity of

30   the phases and the geometry of the Venturi is
sufficient to mix the various phases, the amount of

25

slip can be reduced to a relatively small level and
accurate flow rates can be determined. When
determining flow rates in mixtures of three or more
phases, one or more additional measurements should be
5   taken to determine the particular holdup of interest,
since the single gamma-ray beam would only indicate an
average density for all the phases. For example, two
suitably chosen different gamma-ray energies could be
used to determine the fraction of each of three phases.
10   However in the case where the two of the phases are oil
and gas the following method can be advantageously
used. The individual hydrocarbon phase densities are
determined (as can be the aqueous phase) with an
equation of state as described above.

CLAIMS

We claim:

5   1.   A method of determining the flow rate of a
first fluid phase in a pipe containing at least two
fluid phases, the method comprising the steps of:
        flowing the at least two fluid phases through
        a section of the pipe comprising an upstream pipe,
10   a constriction, and a downstream pipe;
        determining a differential pressure of the
        fluid phases between a first location and a second
        location, the first and second locations
        positioned such that the differential pressure
15   resulting from the fluid phases passing through at
        least part of the constriction can be related to
        the total flow rate of the fluid phases through
        the section of pipe; and
        determining the volume fraction of the first
20   fluid phase by at least in part making a
        measurement at a location downstream of the
        constriction where a substantial amount of mixing
        of the at least two fluid phases is present.

25   2.   The method of claim 1 wherein the
constriction is a Venturi and the substantial amount of
mixing results from the fluid phases passing through
the Venturi.

3.   The method of claim 2 wherein the Venturi
comprises a throat, and the first location is at the
throat.

5   4.   The method of claim 3 wherein the second
location is at the upstream pipe.

         5.   The method of claim 3 wherein the second
location is at the downstream pipe.
10
         6.   The method of claim 3 wherein the throat of
the Venturi comprises approximately parallel walls
defining a diameter of the throat.

15   7.   The method of claim 6 wherein the Venturi
further comprises a diffuser immediately downstream of
the throat, the diffuser comprising walls having a
diameter approximately equal to the diameter of the
throat at an upstream end, and the walls being tapered
20   to a larger diameter towards a downstream end.

         8.   The method of claim 1 wherein the measurement
used in determining the volume fraction of the first
fluid phase is made at a location having a distance
25   from the constriction of approximately 0-20 times the
diameter of the downstream pipe.

         9.   The method of claim 8 wherein the measurement
used in determining the volume fraction of the first
30   fluid phase is made at a location having a distance

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from the constriction of approximately 3-10 times the
diameter of the downstream pipe.

5   10.   The method of claim 9 wherein the measurement
used in determining the volume fraction of the first
fluid phase is made at a location having a distance
from the constriction of approximately 3-5 times the
diameter of the downstream pipe.

10   11.   The method of claim 10 wherein the
measurement used in determining the volume fraction of
the first fluid phase is made at a location having a
distance from the constriction of approximately 5 times
the diameter of the downstream pipe.

15

     12.   The method of claim 1 wherein the measurement
used in determining the volume fraction of the first
fluid phase is made at a location where the flow of the
at least two phases is not stratified.

20

     13.   The method of claim 12 wherein the
measurement used in determining the volume fraction of
the first fluid phase is made at a location where the
velocities of the at least two phases is approximately
25   the same.

     14.   The method of claim 13 wherein the
measurement used in determining the volume fraction of
the first fluid phase is made at a location where the
30   holdup and cut for the first fluid phase are within a
few percent.

29

15.   The method of claim 13 wherein the
measurement used in determining the volume fraction of
the first fluid phase is made at a location where the
5   difference between the holdup and cut for the first
fluid phase is negligible.

16.   The method of claim 1 wherein the measurement
taken in determining the volume fraction of the first
10   fluid phase comprises a density measurement of the at
least two fluid phases.

17.   The method of claim 16 wherein the density is
measured by determining the attenuation of least one
15   gamma-ray beam passing through the fluid phases.

18.   The method of claim 17 wherein the at least
one gamma-ray beam is produced using a weak source.

20   19.   The method of claim 18 wherein the weak
source of the gamma-ray beam comprises a ^{137}Cs source.

20.   The method of claim 18 wherein the weak
source of the gamma-ray beam comprises a ^{133}Ba source.
25

21.   The method of claim 16 wherein the density
measurement is used to determine the transition
pressure for at least one of fluid phases.

22. The method of claim 21 wherein the fluid phase for which the transition pressure is determined substantially comprises hydrocarbons.

5   23. The method of claim 22 wherein the transition pressure is the bubble point of the hydrocarbon fluid phase.

24. The method of claim 1 further comprising the
10   step of determining the individual densities of the at least the two fluid phases.

25. The method of claim 24 wherein the individual densities are determined using an equation of state.
15

26.   The method of claim 25 wherein compositional data is used in determining the individual densities.

27. The method of claim 26 wherein the
20   compositional data is derived from samples of the fluid phases.

28. The method of claim 24 wherein the phase densities are determined from samples of the fluid
25   phases.

29. The method of claim 1 wherein the measurement taken in determining the volume fraction of the first fluid phase comprises a capacitance measurement of the
30   at least two fluid phases.

30.   The method of claim 1 wherein the measurement
taken in determining the volume fraction of the first
fluid phase comprises a resistivity measurement of the
at least two fluid phases.

5

31.   The method of claim 1 wherein the measurement
taken in determining the volume fraction of the first
fluid phase comprises a measurement of the fluid phases
using a gradiomanometer.

10

32.   The method of claim 1 wherein the measurement
taken in determining the volume fraction of the first
fluid phase comprises a measurement of the speed of
sound in the at least two fluid phases.

15

33.   The method of claim 1 wherein the measurement
taken in determining the volume fraction of the first
fluid phase comprises determining either the decay time
or resonance frequency of a vibrating body in the at
20   least two fluid phases.

34.   The method of claim 1 further comprising the
step of determining the flow rate of the first fluid
phase using the volume fraction of the first fluid and
25   the differential pressure, and assuming the velocities
of the first fluid phase and another phase is
substantially the same.

35.   The method of claim 1 wherein the first fluid
30   phase is water and a second fluid phase is oil.

36. The method of claim 1 wherein the constriction is installed in a subterranean hydrocarbon borehole

5   37. The method of claim 36 wherein the constriction is suitable for permanent installation in a hydrocarbon borehole.

38. The method of claim 37 wherein the
10   constriction is dimensioned such that a production logging tool can pass through it.

39. The method of claim 1 wherein the first fluid phase is a gas and a second fluid phase is a liquid.
15

40. The method of claim 39 wherein the first fluid phase is hydrocarbon gas and the second fluid phase is a hydrocarbon liquid.

20   41. The method of claim 40 further comprising the step of determining the individual densities of the at least the two fluid phases using an equation of state and compositional data.

25   42. The method of claim 1 wherein the step of flowing comprises flowing second and third fluid phases through the section of pipe, the method further comprising the step of determining the volume fractions of the second and third fluid phases by making a
30   measurement at a location downstream of the

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constriction where a substantial amount of mixing of
the first, second and third fluid phases is present.

43. The method of claim 42 wherein the first
5   fluid phase is hydrocarbon gas and the second fluid
phase is a hydrocarbon liquid.

44. The method of claim 43 further comprising the
step of determining the individual densities of the
10   first and second fluid phases using an equation of
state and compositional data.

45. An apparatus for determining the flow rate of
a first fluid phase in a pipe containing at least two
15   fluid phases, the apparatus comprising:
          an upstream pipe having a diameter;
          a Venturi having a throat with a throat
diameter, the Venturi disposed immediately
downstream from and in fluid communication with
20   the upstream pipe;
          a downstream pipe having a diameter, disposed
immediately downstream from and in fluid
communication with the Venturi;
          a throat pressure meter configured to
25   determine a throat pressure of the fluid phases
measured at the throat;
          a second pressure meter configured to
determine the pressure of the fluid phases
measured at a second location, the second location
30   positioned such that the change in pressure
resulting from the fluid phases passing through at

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least part of the Venturi can be related to the
total flow rate of the fluid phases; and

a holdup calculator adapted and configured to
determine the volume fraction of the first fluid

5   phase by making a measurement at a location
downstream of the where a substantial amount of
mixing of the at least two fluid phases is
present.

10   46.   The apparatus of claim 45 wherein the
measurement used in determining the volume fraction of
the first fluid phase is made at a location where the
flow of the at least two phases is not stratified.

15   47.   The apparatus of claim 45 wherein the
measurement used in determining the volume fraction of
the first fluid phase is made at a location where the
velocities of the at least two phases is approximately
the same.

20

48.   The apparatus of claim 47 wherein the
measurement used in determining the volume fraction of
the first fluid phase is made at a location where the
holdup and cut for the first fluid phase are within a

25   few percent.

49.   The apparatus of claim 47 wherein the
measurement used in determining the volume fraction of
the first fluid phase is made at a location where the

30   difference between the holdup and cut for the first
fluid phase is negligible.

35

50.   The apparatus of claim 49 wherein the
substantial amount of mixing results from the fluid
phases passing through the Venturi.

5

51.   The apparatus of claim 50 wherein the second
location is on the upstream pipe.

52.   The apparatus of claim 51 wherein the Venturi
10   further comprises a diffuser immediately downstream of
the throat, the diffuser comprising walls having a
diameter at an upstream end approximately equal to the
diameter of the throat, and the walls of the diffuser
being tapered to a larger diameter towards a downstream
15   end of the diffuser.

53.   The apparatus of claim 52 wherein the
upstream pipe, the Venturi, and the downstream pipe are
installed in a subterranean hydrocarbon borehole, and
20   the Venturi is dimensioned such that a production
logging tool can pass through it.

54.   The apparatus of claim 53 wherein the
upstream pipe, the Venturi, and the downstream pipe are
25   suitable for permanent installation in a hydrocarbon
borehole.

55.   The apparatus of claim 54 wherein the
measurement used in determining the volume fraction of
30   the first fluid phase is made at a location having a

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distance from the diffuser of approximately 0-20 times
the diameter of the downstream pipe.

5   56.   The apparatus of claim 55 wherein the
measurement used in determining the volume fraction of
the first fluid phase is made at a location having a
distance from the diffuser of approximately 3-10 times
the diameter of the downstream pipe.

10 57.   The apparatus of claim 56 wherein the
measurement used in determining the volume fraction of
the first fluid phase is made at a location having a
distance from the diffuser of approximately 3-5 times
the diameter of the downstream pipe.

15

58.   The apparatus of claim 57 wherein the
measurement used in determining the volume fraction of
the first fluid phase is made at a location having a
distance from the diffuser of approximately 5 times the

20 diameter of the downstream pipe.

59.   The apparatus of claim 56 wherein the
measurement taken in determining the volume fraction of
the first fluid phase comprises a density measurement

25 of the at least two fluid phases, which is measured by
determining the attenuation of least one gamma-ray beam
passing through the fluid phases.

60.   The apparatus of claim 59 wherein the at

30 least one gamma-ray beam is produced using a weak
source.

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61.   The apparatus of claim 49 wherein the pipe
containing the at least two fluid phases is oriented
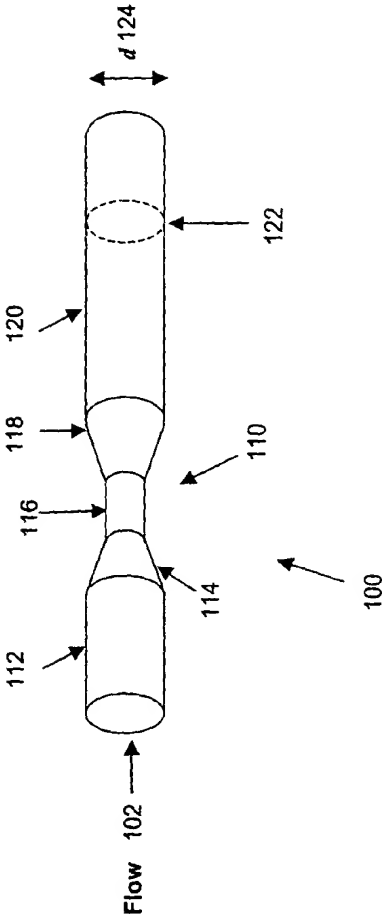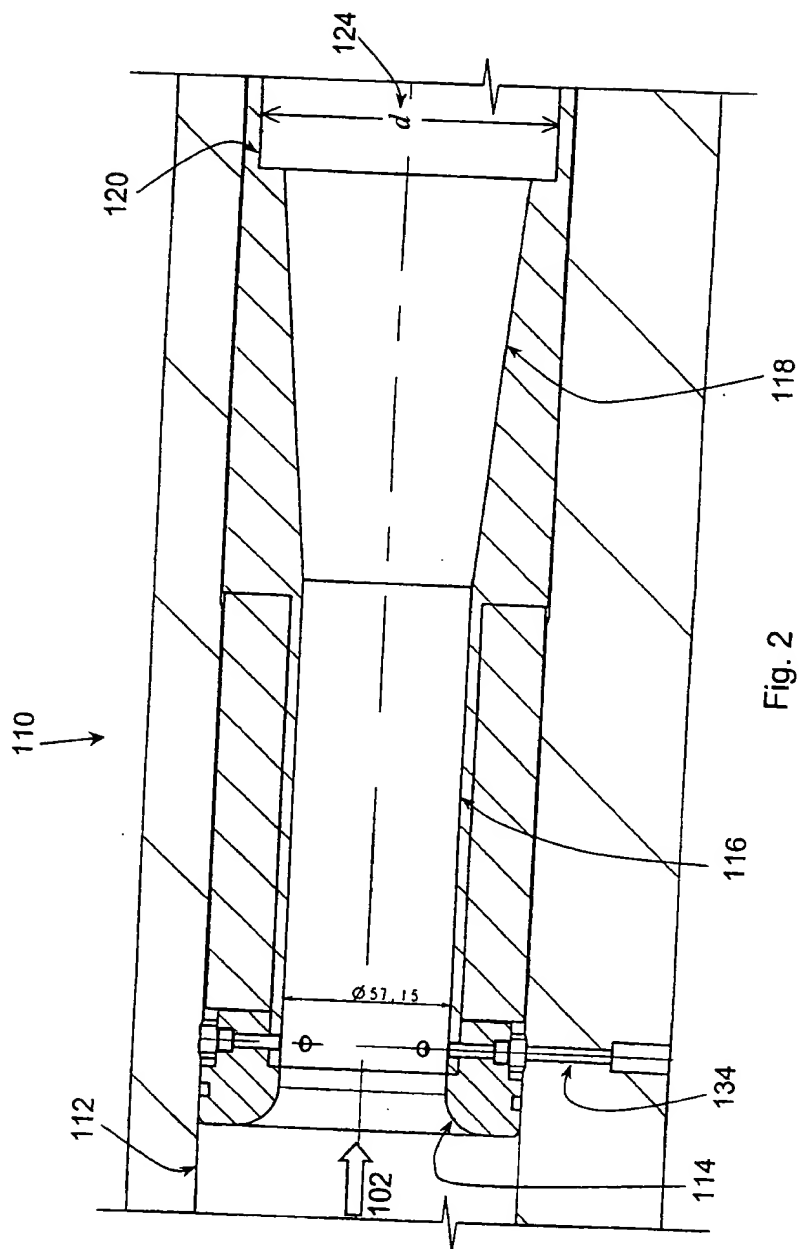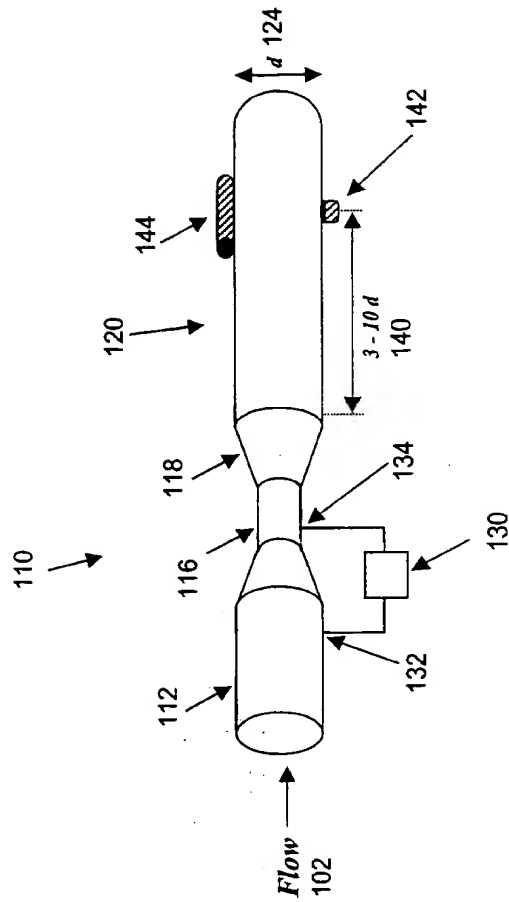approximately horizontally.

5

Fig. 1
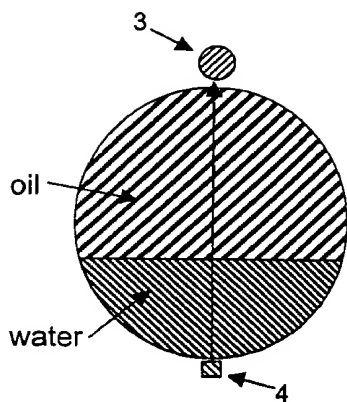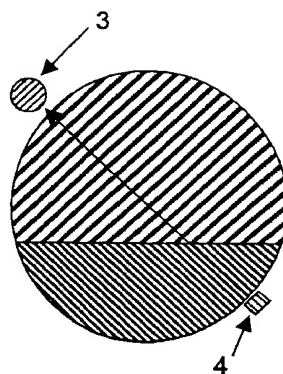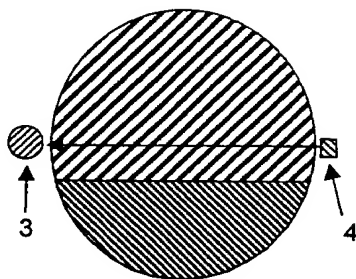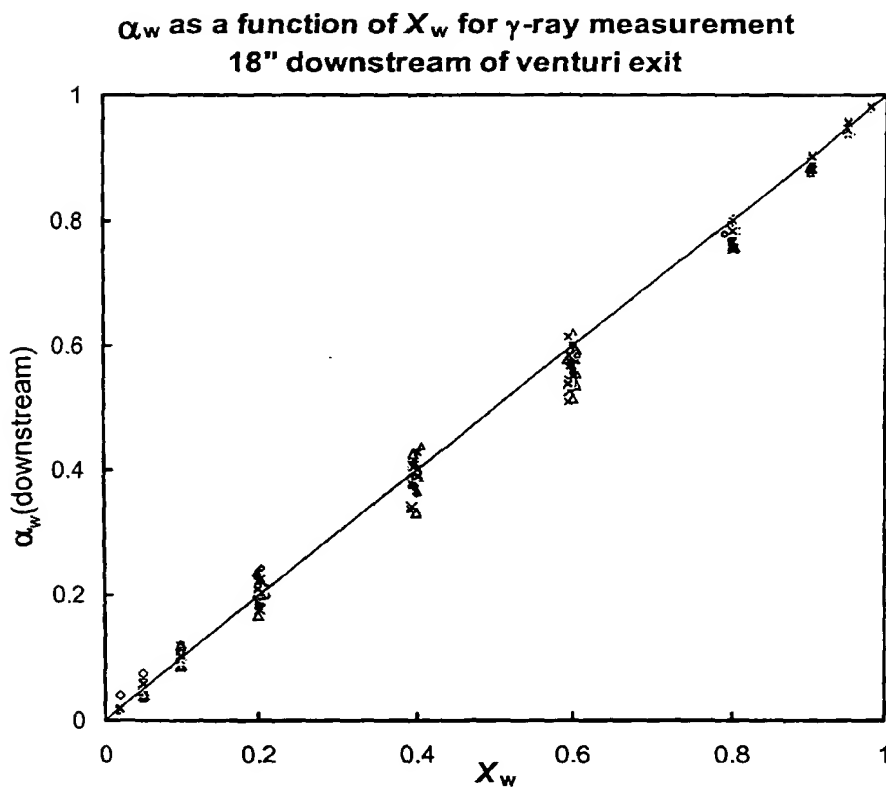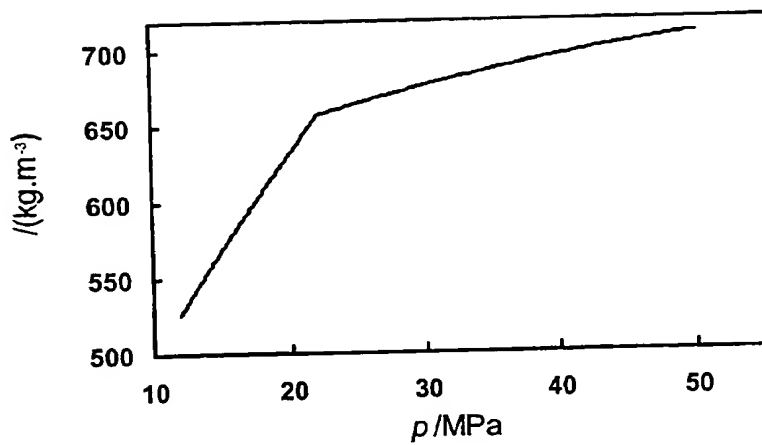
Fig. 2

Fig. 3

Fig. 4
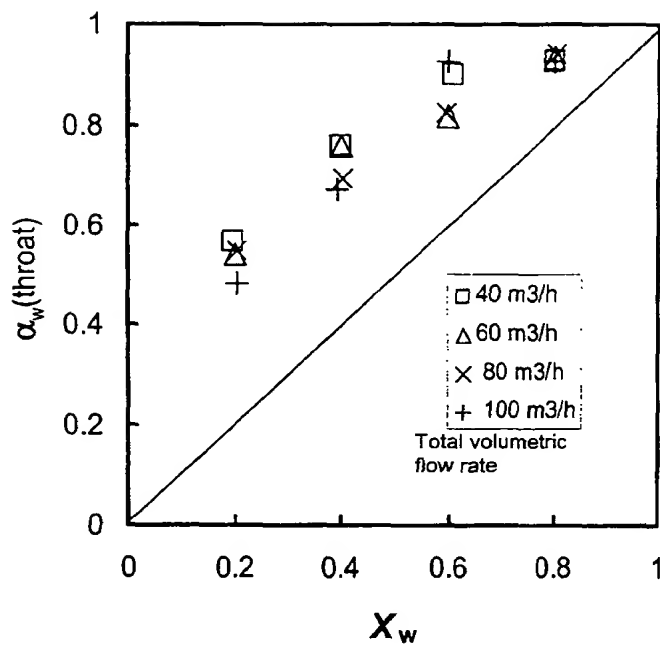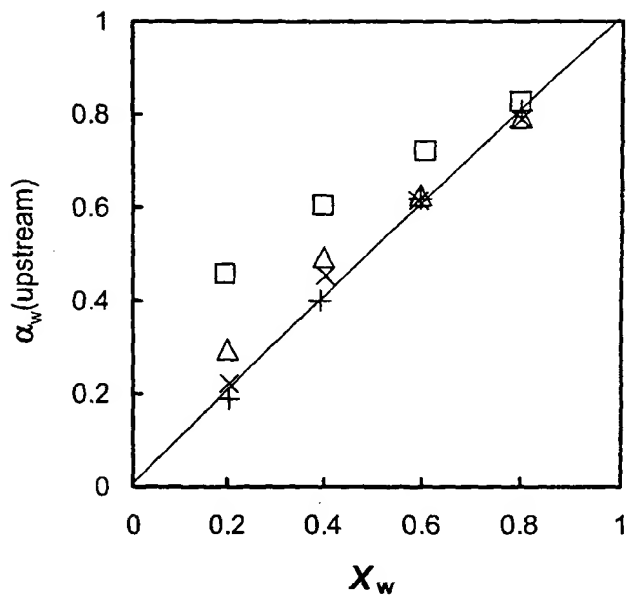
Fig. 5
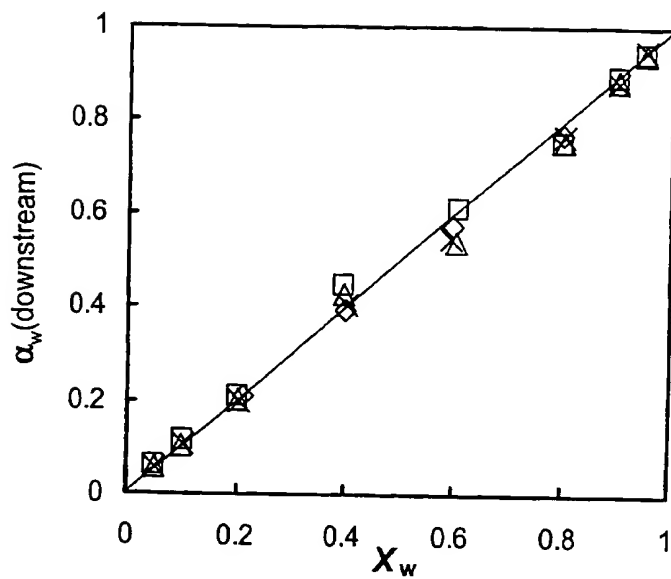
Fig. 6

Fig. 7a   Fig. 7b

Fig. 7c

α_w as a function of X_w for γ-ray measurement
18" downstream of venturi exit

Fig. 8

Fig.9

INTERNATIONAL SEARCH REPORT

A. CLASSIFICATION OF SUBJECT MATTER
IPC 7   G01F1/74   G01F1/44

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
IPC 7   G01F

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)

C. DOCUMENTS CONSIDERED TO BE RELEVANT

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Y		17-23, 30-33, 59,60
A	page 3, paragraph 2 -page 8, paragraph 1; figure 1	11, 25-28, 41,44,58
Y	US 4 441 362 A (CARLSON NORMAN R) 10 April 1984 (1984-04-10) column 7, line 50 -column 8, line 62; figure 2	17-20, 59,60

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| X | Further documents are listed in the continuation of box C. | X | Patent family members are listed in annex. |

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Date of the actual completion of the international search	Date of mailing of the international search report
7 August 2000	11/08/2000

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